DIRECT TESTIMONY AND EXHIBIT

OF

BRIAN HORII

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NOS. 2019-185-E AND 2019-186-E

IN RE: APPLICATIONS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC FOR APPROVAL OF STANDARD OFFER, AVOIDED COST METHODOLOGIES, FORM CONTRACT POWER PURCHASE AGREEMENTS, COMMITMENT TO SELL FORMS, AND OTHER RELATED TERMS AND CONDITIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Brian Horii. My business address is 44 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3"). Founded in 1989, E3 is an energy consulting firm with expertise in helping utilities, regulators, policy makers, developers, and investors make the best strategic decisions possible as they implement new public policies, respond to technological advances, and address customers' shifting expectations.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have over thirty (30) years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission and distribution planning, and distributed energy resources. Prior to joining

E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British Columbia, and Vermont, and have prepared testimonies and avoided cost studies for utilities in New York, New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada and China.

I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Exhibit BKH-1. My prior work experience in this subject matter includes the following:

- Developed the methodology for calculating avoided costs used by the California Public Utilities Commission for evaluation of Distributed Energy Resources ("DER") since 2004;
- Developed the methodology for calculating avoided costs used by the California Energy Commission for evaluation of building energy programs;
- Authored avoided cost studies for BC Hydro, Wisconsin Electric Power Company, and PSI Energy;
- Provided review of, and corrections to, PG&E avoided cost models used in their general electric rate case;
- Developed the integrated planning model used by Con Edison and Orange and Rockland Utilities to determine least cost DER supply plans for their network systems;

- Developed the hourly generation dispatch model used by El Paso Electric Company to evaluate the marginal cost impacts of their off-system sales and purchases;
- Produced publicly vetted tools used in California for the evaluation of energy efficiency programs, distributed generation, demand response, and storage programs;
- Analyzed the cost impacts of electricity generation market restructuring in Alaska, Canada, and China; and
- Developed the "Public Tool" used by California stakeholders to evaluate Net Energy Metering program revisions in California.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes, I previously testified before this Commission on behalf of the Office of Regulatory Staff ("ORS") in Docket Nos. 2017-2-E and 2018-2-E.

Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?

A. ORS retained E3 to conduct analysis, review, and develop recommendations regarding the Companies':

1) Standard offers;
2) Avoided cost methodologies;
3) Form power purchase agreements ("PPA");
4) Commitment to sell forms;
5) Any other terms or conditions necessary to implement Section 58-41-20(A) of the South Carolina Energy Freedom Act ("Act 62" or the "Act");

6) Confirm the avoided cost methodology meets the Public Utility Regulatory Policies Act of 1978 ("PURPA") requirements;
7) Verify the avoided energy and capacity cost rates requested by the Companies are a reasonable result of the Companies' avoided cost methodology; and
8) Verify the solar integration services charges requested by the Companies are reasonable and quantified correctly.

Q. UNDER ACT 62, WHAT ELEMENTS INFORMED YOUR REVIEW OF THE COMPANIES' FILINGS?

A. My review and resulting recommendations are based on standard industry principles in establishing avoided costs for electrical utilities and relied on the guidance provided in Section 58-41-20(A) of Act 62. Specifically,

> "[a]ny decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the FERC's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."

In addition, ORS relied on Section 16 of the Act which states:

> "Notwithstanding another provision of this act, or another provision of law, no costs or expenses incurred nor any payments made by the electric utility in compliance or in accordance with this act must be included in the electrical utility's rates or otherwise borne by the general body of South Carolina retail customers of the electrical utility without an affirmative finding supported by the preponderance of evidence of record and conclusion in a written order by the Public Service Commission that such expense, cost or payment was reasonable and prudent and made in the best interest of the electrical utility's general body of customers."

Q. IN YOUR OPINION, WERE THE COMPANIES' FILINGS IN THESE DOCKETS REASONABLY TRANSPARENT FOR YOUR INDEPENDENT REVIEW AND ANALYSIS?

A. The Companies provided data responses and supporting information to their filings that allowed me to conduct my analysis, assess the reasonableness of their proposals, and develop recommendations regarding the implementation of Act 62.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR COMMISSION CONSIDERATION TO IMPROVE TRANSPARENCY IN FUTURE PROCEEDINGS?

A. Yes. I do understand the time constraints in implementation of the Act. While I was able to do a quick assessment and identify clear issues with some of the Companies' assumptions, future proceedings would benefit from a more expanded period of time allowed for testimony and rebuttal testimonies. For comparison, the proceedings in California that determine avoided costs and ratemaking, parties are provided with approximately four (4) months to prepare testimony after the utility application is filed, with rebuttal testimony from all parties due about three (3) months later. Other than the increased timeframe for parties to conduct analysis and develop positions, this timeframe also allows the utility more time to respond to data requests and provides all parties with more time to potentially settle any emerging issues.

Q. BRIEFLY DESCRIBE THE REQUIREMENTS OF PURPA AND HOW THE REQUIREMENTS RELATE TO DEC'S PROPOSED SCHEDULE PP (SC) PURCHASED POWER ("SCHEDULE PP") AND DEP'S PROPOSED

PURCHASED POWER SCHEDULE PP-5 ("SCHEDULE PP-5" OR COLLECTIVELY "STANDARD OFFERS").

A. In 1978, as part of the National Energy Act, Congress passed PURPA. The policy was designed, among other things, to encourage conservation of electric energy, increase efficiency in use of facilities and resources by utilities, and produce more equitable retail rates for electric consumers.

To help accomplish PURPA goals, a special class of generating facilities called Qualifying Facilities ("QFs") was established. QFs receive special rate and regulatory treatments, including the ability to sell capacity and energy to electric utilities. All electric utilities, regardless of ownership structure, must purchase energy and/or capacity from, interconnect to, and sell back-up power to a QF. This obligation is waived if the QF has non-discriminatory access to competitive wholesale energy and long-term capacity markets.

In the DEC and DEP service territories, Small Power Producers and Cogenerators that are designated as QFs and have capacity less than or equal to two (2) megawatts ("MW") are compensated under the proposed Standard Offers. I will address my analysis and calculations of proposed rates and charges later in my direct testimony.

Q. ARE THE REQUIREMENTS OF ACT 62 CONSISTENT WITH PURPA?

A. Yes. As is consistent with a federal statutory mandate, PURPA requires Federal Energy Regulatory Commission ("FERC") to promulgate rules, that ensure that utilities offer avoided cost rates which are just and reasonable to electric consumers and in the public interest, and not discriminatory against qualifying small power producers. Act 62 specifies that electric utilities offer certain contract terms to small power producers, subject to approval by this Commission. Under current FERC regulations, state regulatory authorities such as this Commission have broad latitude in determining state specific PURPA policies and I believe the requirements of Act 62 are consistent with PURPA or implementing regulations promulgated by the FERC.

I. Avoided Energy Analysis, Discussion and Recommendations

Q. COMPANY WITNESS SNIDER STATES IN HIS DIRECT TESTIMONY THAT THE COMPANIES USE THE "PEAKER METHODOLOGY" TO FORECAST AVOIDED ENERGY AND CAPACITY COSTS (PAGE 10). DO YOU AGREE WITH THIS?

A. I do agree that the Companies use the peaker methodology to forecast avoided capacity costs. However, as described by witness Snider beginning on page 21 of his direct testimony, the Companies use a different methodology to forecast avoided energy costs.

Q. DESCRIBE THE METHODOLOGY THE COMPANIES USED TO CALCULATE PROPOSED AVOIDED ENERGY COSTS.

A. The Companies calculate avoided energy costs using a methodology known as the Differential Revenue Requirement ("DRR"). The DRR method calculates the revenue requirements associated with two (2) resource plan scenarios: a base case without a QF, and a change case with the addition of a QF.

For the avoided energy cost calculations, in both the base case and the change case, the Companies use a production cost model to simulate the commitment of generating units to serve load on an hourly basis over a 10-year Integrated Resource Plan ("IRP") planning horizon. The base case is constructed by using load forecasts and supply side resources as described in the 2019 IRP. The change case modifies the base case load forecasts and supply side resources by modeling the addition of 100 megawatts ("MW") of no-cost generation to measure the reduction in total production cost. Finally, the avoided energy costs are levelized and adjusted for taxes and working capital as well as line losses.

Q. IS THE METHOD USED BY THE COMPANIES TO CALCULATE AVOIDED ENERGY COSTS CONSISTENT WITH PURPA AND WITH THE METHODOLOGY PREVIOUSLY APPROVED BY THE COMMISSION?

A. Yes. This is one of the generally accepted methods for calculating PURPA avoided energy costs and is used throughout the United States.

Q. DESCRIBE THE UPDATES MADE BY THE COMPANIES TO THE AVOIDED ENERGY COSTS AS PROPOSED IN THESE DOCKETS COMPARED TO THOSE PREVIOUSLY APPROVED BY THE COMMISSION.

A. My review of the Companie' current testimony, testimony filed in Docket No. 1995-1192-E and work papers indicates a few differences which account for the variance in avoided energy costs between those requested in these dockets and the avoided energy costs approved by the Commission in 2016. Specifically, the rates approved in 2016 were based on and identical to the rates from North Carolina Utilities Commission's Docket E-100, Sub 140.[1]

The most significant driver of avoided energy cost changes is updated fuel price forecasts. Other variables include differences between the IRPs filed by the Companies in 2016 and 2019, including differences in purchased power amounts, changes in projected

[1] Docket No. 1995-1192-E; Order No. 2016-349, p. 1 (May 12, 2016).

generation capacities of various utility-owned generation technologies, and reduced growth in long-term annual sales forecasts.

In addition to these load and generation changes, the Companies have updated the Standard Offer avoided energy rate designs by adding more hourly and seasonal granularity to more accurately reflect the hours when QFs provide energy value to the Companies. The Companies have proposed nine (9) time of use ("TOU") periods for each of their service territories. The year is divided into three (3) seasons (Summer: June - September; Winter: December – February; and Shoulder for all other months) with three (3) TOU periods for each season. The TOU periods differ for DEC and DEP as a reflection of the differing hourly avoided energy costs for each utility.

Q. ARE THE UPDATES TO THE AVOIDED ENERGY COSTS AND RATE DESIGN A REASONABLE AND CONSISTENT RESULT OF THE METHODOLOGY USED BY THE COMPANIES?

A. Yes. I reviewed the fuel price forecasts and other variables the Companies incorporated in calculating the avoided energy costs for both the 2016 and 2019 avoided cost proceedings. The forecast methodologies and values are consistent with market knowledge of fuel price forecasts and generator cost forecasts available at the time of the Companies' forecasts. In the intervening years the Companies have seen reductions in load forecasts between the 2016 IRP and the 2019 IRP. Similarly, both Companies' 2019 IRPs show increased forecasts of installed solar penetration relative to forecasts for the same time period in the 2016 IRPs. Nevertheless, I believe these changes to the load and resource fleet are not likely to change the types of units that are on the margin during the hourly avoided energy analysis. This means that during each hour of the simulated system dispatch, the most expensive generator (which sets the avoided cost of electricity for the hour) is likely to be the same type of unit that was identified in the prior IRP. Given this, the most meaningful driver of the change in avoided energy costs is the fuel price forecast change and thus it is reasonable to expect the change in avoided energy cost calculations track closely with the change in fuel price forecasts.

Q. DO YOU RECOMMEND ANY CHANGES TO THE COMPANIES' AVOIDED ENERGY COST CALCULATIONS OR RESULTING RATES APPLICABLE TO THE STANDARD OFFER TARIFFS?

A. No. Based on my review, the avoided energy costs reflected by the Companies in the Standard Offer tariffs are a reasonable result of the Companies' calculations. The calculation methodology is consistent with PURPA and the Commission's prior approval.

II. Avoided Capacity Analysis, Discussion and Recommendations

Q. DESCRIBE THE METHODOLOGY THE COMPANIES USED TO CALCULATE PROPOSED AVOIDED CAPACITY COSTS.

A. The Companies use the "peaker" method to quantify the avoided cost of generation capacity. The peaker method uses the capital and fixed operating and maintenance ("O&M") costs of a new advanced simple cycle combustion turbine ("CT") as the proxy for the cost of generation capacity. The cost of the CT is adjusted upward for return on and of capital, income taxes, property taxes, insurance, working capital, a general plant loading factor, losses, and a performance adjustment factor. The annual adjusted cost of the CT is then used to represent the avoided cost of generating capacity for the years in which the Companies show a need for capacity in their respective IRPs.

Q. IS THE METHOD USED BY THE COMPANIES TO CALCULATE AVOIDED CAPACITY COSTS CONSISTENT WITH PURPA AND THE METHODOLOGY PREVIOSLY APPROVED BY THE COMMISSION?

A. Yes. This method is one of the generally accepted methods for calculating PURPA avoided capacity costs and is used throughout the United States.

Q. THE COMPANIES' PROPOSED AVOIDED CAPACITY RATES FOR DEC ARE SIGNIFICANTLY LOWER THAN THE PROPOSED AVOIDED CAPACITY RATES FOR DEP. IS THIS DIFFERENCE JUSTIFIED?

A. Yes. The goal of avoided capacity rates is to match the pricing to the incremental costs of providing the demand service. The Companies recently filed 2019 IRPs shows DEP has a need for additional generation capacity starting in 2020, while DEC's need for additional capacity is not until 2026. Therefore, over the 10-year analysis horizon (2020 through 2029), DEP has a need for capacity in ten of the ten years, whereas DEC only needs capacity in four of the ten years. Moreover, given that DEC's need for capacity occurs farther into the future, the value of avoiding that capacity is reduced when discounted to 2020 dollars.

Q. WAS THE COMPANIES' USE OF THE RECENTLY FILED 2019 IRPS APPROPRIATE, REASONABLE, AND TRANSPARENT?

A. Yes. While the time constraints required by Act 62 shortened my review of the 2019 IRP, the Companies used their most recent publicly available estimates of load and resources to calculate proposed avoided costs. Using older vintages of the IRPs would lock in avoided cost values based on fuel prices, generator information, and load forecasts that the Companies have updated. Thus, to the extent possible, it is appropriate, reasonable, and transparent to use the most recent publicly available data describing the Companies' loads and resource forecasts.

Q. THE LOAD AND RESOURCE BALANCE TABLE THAT DEC PROVIDED TO ORS AS THE BASIS FOR THEIR CAPACITY NEED DETERMINATION INDICATES INCREASES OF GENERATION CAPACITY VIA CAPACITY INCREASES OR UPRATES IN 2021 THROUGH 2024.[2] DO THESE CAPACITY ADDITIONS REQUIRE DEC TO RECOGNIZE AVOIDED CAPACITY COSTS IN THESE YEARS?

A. No. There is no need for additional system capacity in 2021 through 2024 so the addition of QF capacity would not avoid or defer the uprate projects. Because the projects would be unaffected, there would be no avoided capacity cost associated with the projects.

Q. THE DEC LOAD AND RESOURCE BALANCE TABLE ALSO SHOWS THE ADDITION OF THE LINCOLN COMBUSTION TURBINE IN 2025. SHOULD DEC USE 2025 AS THE FIRST YEAR OF AVOIDED CAPACITY COSTS INSTEAD OF 2026?

A. No. Moving the first year of avoided capacity costs to 2025 instead of 2026 would incorrectly increase the avoided capacity payments to QFs. The Lincoln combustion turbine has already been approved and commenced construction. Additional QF capacity should not affect its in-service date and therefore not result in avoided capacity costs in 2025. Therefore, the first year of avoided capacity should continue to be 2026, not 2025.

[2] DEC response to ORS Audit Information Request 2-12

Q. DO YOU RECOMMEND ANY CHANGES TO THE COMPANIES' AVOIDED CAPACITY COST CALCULATIONS OR RESULTING RATES APPLICABLE TO THE STANDARD OFFER TARIFFS?

A. Yes. I recommend DEC make two (2) changes to the avoided capacity cost calculations:

1) Increase the Fixed Charge Rate for a CT; and
2) Correct the allocation of capacity costs to seasons and time of day.

Q. WHY SHOULD DEC INCREASE THE FIXED CHARGE RATE FOR A CT AND HOW DOES THAT IMPACT THE RESULTING AVOIDED CAPACITY RATES?

A. It is common industry practice to calculate the annual value of generation capacity as the direct cost of the CT multiplied by a Fixed Charge Rate. The fixed charge rate is the percentage of total plant cost that is required each year over the economic life of the plant to recover its full capital-related revenue requirement.[3] DEC follows this approach, but uses a 35-year economic life for the CT, rather than a 20-year economic life for the CT that is commonly used in jurisdictions like California for their electricity avoided costs, PJM for their Cost of New Entry report, and by the highly regarded Lazards Levelized Cost of Energy Analysis report.[4] By using an overly long life in the Fixed Charge Rate calculation,

[3] DEC and DEP calculate costs related to General Plant, Fixed O&M, and Working Capital separately, so those costs are not included in their calculation of the Fixed Charge Rate.
[4] ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/ACC_2019_v1b.xlsb

https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx

https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

DEC is spreading the capital-related costs of the CT over an excessive number of years and artificially lowering the estimate of costs that would need to be collected in each year for the CT owner. Correcting the CT life to 20 years in DEC's annualization tool provided by the Company[5] increases the CT Fixed Charge Rate from 7.635% per year to 9.931% per year. This increases the avoided capacity cost by 29%.

Q. WHY SHOULD DEC CORRECT THE ALLOCATION OF CAPACITY COSTS TO SEASONS AND TIME OF DAY?

A. DEC correctly allocates the capacity costs based on the relative Loss of Load Expectation ("LOLE") in each time period. However, DEC uses LOLEs based on 3,500 megawatts ("MW") of solar penetration on the DEC system. 3,500 MW of solar penetration is "Tranche 4" in the analysis nomenclature which is the highest level of solar penetration evaluated, and reflects solar penetration levels far in exceedance of current levels. DEC's allocations of avoided capacity costs to season and time of day, therefore reflect capacity needs too far into the future, rather than reflect what system capacity needs would be in 2020 when there are only approximately 840 MW (Company witness Snider direct testimony, page 35) of solar on the system.

This is problematic because the timing of the need for capacity when there are 840 MW of solar on the DEC system is not the same as the timing of the need for capacity when there are 3,500 MW of solar on the system. With the higher level of solar generation, the need for system capacity shifts away from hours when the already installed solar is generating.

[5] DEC confidential response to ORS Audit Information Request 2-2.

Q. SINCE THE DEC SYSTEM MAY EVENTUALLY HAVE 3,500 MW OF SOLAR INSTALLED, WOULD IT BE APPROPRIATE TO USE THE 3,500 MW CASE TO DETERMINE THE ALLOCATION FACTORS FOR 2020 CONTRACTS?

A. No. Even if a contract were to span years that have that high of a level of solar penetration, the incremental value the contract provides is a function of the timeframe when the resource is installed. Consider the following highly stylized hypothetical examples:

Example #1: Utility A's current peak occurs at 4:00pm and the peak in ten (10) years is expected to occur at 8:00pm because of increasing solar generation. Utility A offers capacity credits based on what it expects in ten (10) years, so all the credits occur at 8:00pm. The result is that no solar is built, and the peak remains at 4:00pm. Utility A tried to cure the problem it might have, and by doing so failed to address the problem it already has.

Example #2: Utility A's current peak occurs at 4:00pm and Utility A offers capacity credits for 4:00pm. With the acquisition of additional solar the peak shifts to 6:00pm. Since the peak is now at 6:00pm, did Utility A waste money by providing that 4:00pm credit? No. The solar that was built for the 4:00pm peak is performing so well that it eliminated 4:00pm as the peak problem. If that solar were to disappear, however, the 4:00pm peak could reappear, so there remains value to that solar. To be sure the next tranche of credits would be for a 6:00pm peak, with the peak moving later and later with each tranche of solar.

At some point, the amount and timing of the capacity credits may preclude solar from being added --- but that only means that the next tranche of solar is not cost effective. The prior tranches are still providing value via their reduction in their peak that helped shift the new peak to later hours.

Q. WHAT IS YOUR RECOMMENDATION FOR DEC CAPACITY ALLOCATION FACTORS?

A. In looking at the avoided costs of new QFs in 2020 (which is the timeframe of the projects that will be affected by the rates decided in these dockets), it is important to reflect cost changes relative to current conditions. Because these avoided capacity costs will be used to calculate compensation for solar in 2020, it is appropriate to use LOLEs that are based on current solar penetration levels.

Two of my guiding principles in evaluating the Companies' avoided cost-based credits are to align the credits to the value that the Standard Offer resources could provide, and to provide accurate price signals to encourage the adoption of cost-effective new resources. Updating the allocation of capacity costs to season and time of day will promote both of these goals as well as the intent of PURPA.

I recommend using the LOLE from the "Existing plus Transition" case from the LOLE study provided by the Companies in Docket No. 1995-1192-E. The solar penetration levels of the "Existing plus Transition" case most closely resembles current levels and the LOLE from that case would shift capacity allocation factors higher in the summer, and also change the allocation of capacity between winter morning and winter evening. My recommended capacity allocation factors compared to those proposed by DEC are shown below in Table 1.

Table 1: Capacity Cost Allocation Factors

PERIOD	DEC PROPOSED	E3 RECOMMENDED
SUMMER	10%	40%
WINTER MORNING	68%	48%
WINTER EVENING	22%	12%

Q. WHAT AVOIDED CAPACITY RATES DO YOU RECOMMEND FOR DEC?

A. My recommended DEC avoided capacity credits for the 10-year fixed rates are shown in Table 2 below. I do not recommend any changes to the DEC proposed variable and 5-year fixed capacity rates as there is no identified need for system capacity for DEC within the next five (5) years.

Table 2: E3 DEC Avoided Capacity Rates for 10-Yr Fixed Rates (Distribution)

	Summer On-Peak	Winter AM On-Peak	Winter PM On-Peak
DEC Proposed Rates (¢/kWh)	0.86	3.99	1.29
E3 Recommended Rates (¢/kWh)	**4.40**	**3.60**	**0.90**

The season and on-peak period definitions remain unchanged from DEC's proposal.

Q. HOW DID YOU CALCULATE YOUR RECOMMENDED AVOIDED CAPACITY RATES FOR DEC?

A. I calculated my recommended avoided capacity values using the information provided by Company witness Snider as Snider DEC Exhibit 1 (Confidential). I updated the DEC model for 1) the Fixed Charge Rate using my recommended 20-year economic life for a CT, and 2) my recommended changes in seasonal and time of day capacity cost allocations.

Q. DO YOU RECOMMEND ANY CHANGES TO THE DEP PROPOSED AVOIDED CAPACITY RATES?

A. Yes. As with DEC, DEP also used a 35-year economic life for a CT instead of a 20-year economic life to calculate the Fixed Charge Rate for a CT. Correcting for that error increases the DEP Fixed Charge Rate from 7.189% per year to 9.394% per year, which increases the capacity cost by 30.7%.

Similarly, correcting the seasonal and time of day capacity allocation factors for DEP to reflect the "Existing plus Transition" amount of solar penetration instead of the overly high "Tranche 4" results in a very small change in the capacity allocation factors. The summer peak allocation would change from DEP's proposed 0% to 1%, and the winter morning peak share would drop from 70% to 69%. The winter evening on-peak allocation would remain the same. My recommended DEP capacity rates are shown below in Table 3.

Table 3: E3 Recommended DEP Avoided Capacity Rates (Distribution)

	Summer On-Peak	Winter AM On-Peak	Winter PM On-Peak
DEP Proposed Variable Credit (¢/kWh)	0	10.82	4.64
E3 Variable Credit (¢/kWh)	**0.29**	**13.69**	**5.95**
DEP Proposed 5-year Fixed Credit (¢/kWh)	0	11.03	4.73
E3 5-year Fixed Credit (¢/kWh)	**0.30**	**13.95**	**6.07**
DEP Proposed 10-year Fixed Credit(¢/kWh)	0	11.36	4.87
E3 10-year Fixed Credit(¢/kWh)	**0.30**	**14.37**	**6.25**

III. Integration Services Charges Analysis, Discussion and Recommendations

Q. DOES INTEGRATING RENEWABLE GENERATION CREATE ADDITIONAL COSTS FOR UTILITIES?

A. Yes. E3 conducted extensive work in California and Hawaii where renewable generation comprises a large portion of generation resources. In our own modeling, E3 has seen that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation. The cost impact can include higher start-up costs, fuel costs, and O&M costs resulting from resources operating at levels below their maximum efficiency to allow upward headroom to ramp up output. Costs can also increase for additional generation plant required to provide additional flexible capacity.

Q. DO YOU CONSIDER THE COMPANIES' ANALYSIS TO BE AN ACCEPTABLE APPROACH TO ESTIMATING SOLAR INTEGRATION COSTS?

A. Yes. In the Solar Ancillary Service Study ("Study") performed by Astrapé Consulting (Company witness Wintermantel Exhibit 2), the consultants evaluated the additional resources (via increased operating reserve requirements) needed to maintain a specific level of reliability with and without incremental solar resources, as well as the increased operating costs for the generation fleet to respond to solar output intermittency.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING THE COMPANIES' PROPOSED INTEGRATION SERVICES CHARGES?

A. Yes. I have two (2) primary observations about the proposed integration services charges:

1) The results of the Study may indicate higher solar integration costs than would be required if the Companies sought to minimize those integration costs; and
2) The Companies' proposal to use average integration costs that update annually.

Q. HOW CAN THE COMPANIES SEEK TO MINIMIZE SOLAR INTEGRATION COSTS?

A. Integration costs could potentially be reduced in the following ways:

1) If additional operating reserve requirements were dynamically linked to solar output levels and the varying risk of solar output reductions;
2) Employing improved solar output forecast methods to reduce the forecast error between expected and actual solar output; and
3) Employing pre-curtailment of solar to reduce the cost to address solar over-forecast error.

Q. HOW COULD DYNAMIC OPERATING RESERVE LEVELS LOWER INTEGRATION COSTS?

A. In the Companies' integration cost modeling, the operating reserve percentage is increased for all hours in order to hold overall annual reliability constant between the cases with solar and the cases without solar. However, the higher operating reserve percentage is the same for all hours, while the risk of an unforecasted drop in solar output is not the same across all hours. For example, as the Companies show in Tables 10 and 14 of the Study, solar forecast error is lowest at both high and low levels of average solar output. This is intuitive as clear sunny days and completely overcast days are likely to have less risk of a drop in solar output than a day with a mix of clear sky and clouds. By requiring less of an operating reserve increase in those hours where there is lower risk of a drop in solar output, the additional costs of solar integration could be reduced.

Q. HOW COULD IMPROVED FORECASTING METHODS REDUCE INTEGRATION COSTS?

A. Reducing the solar forecast error would allow for more efficient dispatch of existing resources and more accurate determination of the needed operating reserves. There are currently commercial products and research efforts underway to improve solar forecasts,[6] and such methods may be a cost-effective way to further lower solar integration costs.

Q. HOW COULD SOLAR PRE-CURTAILMENT REDUCE INTEGRATION COSTS?

A. Pre-curtailment or under-scheduling of solar generation resources reduces the uncertainty of a drop in solar production, and therefore reduces the operating reserves that would be required for solar forecast error. Pre-curtailment is the recognition of expected curtailment levels in scheduling solar generation in order to reduce the need for increased operating reserves. If it is anticipated that solar would be curtailed on the operating day due to oversupply, utility system operators could reduce the amount of additional reserves they would otherwise procure to accommodate a potential solar over-forecast. For example, if DEC or DEP system operators expect to curtail 60 MW of solar output, but there is also a risk of a 100 MW drop in solar output, the Companies' operators need to only accommodate for 40 MW of downward solar risk when they recognize that 60 MW is expected to be curtailed but could easily be utilized if needed. Put another way, headroom

[6] Examples of solar forecast research:
https://medium.com/@TheLeadSA/five-minute-forecast-a-win-for-solar-energy-industry-7c1df91cd296
https://solcast.com/utility-scale-solar/
https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Market-Participant-5-Minute-Self-Forecast
https://ral.ucar.edu/solutions/how-advanced-forecasting-making-it-easier-integrate-solar-grid

needed on other resources for solar forecast error is reduced when the operator forecasts the need to curtail solar before real time.

Under-scheduling involves scheduling solar for a lower than forecast amount of output in order to reduce utility load following costs by helping manage the expected level of ramping needed in the morning and evening. Although there would be associated costs to compensate the solar generator for the lessened purchased output, that cost could be lower than the associated ramping costs.

Q. WHAT COULD BE A POSSIBLE OUTCOME DUE TO THE COMPANIES' USE OF AN ANNUALLY UPDATED AVERAGE SOLAR INTEGRATION COST FOR ALL QFS?

A. The Companies' proposed QF rates are intended to reflect avoided costs, which means the going forward costs to provide a service. As mentioned previously, my guiding principle is to match the pricing to the incremental costs of providing the service (energy or demand). The incremental solar integration services charges reflect the additional cost for new solar resources to be added to the Companies' systems. The Companies' proposed rate design uses average integration services charges instead of actual integration services charges. It is my opinion this practice would dampen this price signal and socialize the higher cost over both new and existing solar resources. This would encourage the over installation of solar beyond 2020 because the new solar entering the market would be subsidized by existing solar and would not be subject to the full cost of integrating onto the Companies' electric systems.

Q. DID YOU INDEPENDENTLY QUANTIFY ALTERNATIVE VALUES FOR THE COMPANIES' INTEGRATION SERVICES CHARGES?

A. No. The timeframes established for these dockets did not allow for a detailed analysis to quantify alternative values to the Companies' proposed integration services charges. My observations should be used to inform future integration studies performed for the Companies' balancing authorities.

Q. PLEASE EXPLAIN YOUR RECOMMENDATIONS REGARDING SOLAR INTEGRATION SERVICES CHARGES FOR THE COMPANIES' STANDARD OFFERS.

A. It is appropriate to recognize the Companies will incur additional integration costs associated with integrating large amounts of solar generation onto the Companies' grid. As an initial step or on an interim basis, I recommend the Companies' solar integration services charges of $1.10/MWh for DEC and $2.39/MWh for DEP be approved. I also recommend these charges be adopted as <u>upper limits</u> for solar integration service charges for contracts signed under the Standard Offers proposed by the Companies. The Companies should conduct additional integration studies, and if lower incremental integration services charges were to be adopted for future offers, the integration services charges for this vintage of Standard Offer contracts should be updated to reflect those lower values starting with the effective date of the new offers.

The rationale for setting the integration services charges as an upper limit is that if costs for the next increment of solar installations is higher, it should be the responsibility of those installations to incur those higher costs. However, if the incremental costs are lower, I would expect the reduction in incremental costs to be due to some major change in how renewable integration is managed, and such cost reductions should be applied to all existing and incremental projects.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THE COMPANIES' ANALYSIS REGARDING FUTURE INTEGRATION SERVICES CHARGES UPDATES TO THEIR STANDARD OFFERS?

A. Yes. I recommend that the Companies be required to update their analysis for future changes to their Standard Offers. As part of the update, the Companies should be required to conduct technical workshops to gain input from the solar community and other stakeholders. Areas of agreement and disagreement should also be documented in a formal stakeholder process report to be submitted to the Commission along with the integration study.

Q. WHY DO YOU BELIEVE IT IS IMPORTANT TO HAVE STAKEHOLDER INVOLVEMENT IN THE UPDATING OF INTEGRATION SERVICES CHARGES?

A. There are three (3) primary reasons that stakeholder engagement is important for this issue:

1) As research on renewable integration evolves and improves, stakeholders may be able to suggest advances and improvements to the Companies' analysis;
2) Renewable integration charges are a new category of avoided costs, without the same rich history of estimation methods and approaches as the other cost categories. The stakeholder process would promote a more efficient interchange of ideas than may be realized through the testimony and hearing process; and

3) Renewable integration costs are intended to be charged primarily to the solar community, and as such the solar community should have a voice in the determination of the charges. For example, allowing more utility control of solar plant "dispatch" to allow for lower integration services charges could be economically superior to the assumption that solar could only be curtailed due to minimum generation limits. Such options might not be analyzed without the solar community's input.

IV. Form Contract PPAs and Commitment to Sell Forms Recommendations

Q. BASED ON YOUR EXPERIENCE, ARE THE COMPANIES' PROPOSED NOTICE OF COMMITMENT TO SELL FORM CONSISTENT WITH PURPA AND FERC IMPLEMENTATION GUIDELINES?

A. Yes**.** It is my understanding that the notice of commitment to sell forms, proposed by the Companies in accordance with the requirement in Act 62, are consistent with PURPA and FERC. The commitment to sell forms function to establish a non-contractual legally enforceable obligation ("LEO") option for a QF which contractually obligates the QF to sell and deliver its full output to the utility and the utility to purchase the delivered energy and capacity at the utility's avoided cost rates over the specified term length. Furthermore, the requirements contained in the notice of commitment to sell form (such as FERC certification or self-certification as a qualifying facility, demonstrating site control, and requirement to submit an interconnection request to the utility) are consistent with PURPA and FERC implementation guidelines, which have given state regulatory authorities latitude in determining appropriate requirement standards.

Q. DOES THE COMPANIES' STANDARD FORM PPA FOR LARGE QFs CONFORM TO INDUSTRY STANDARDS?

A. Yes. Based on my experience, the Companies' proposed standard form PPA for large QFs conforms to industry standard terms and conditions, is non-discriminatory to QFs, commercially reasonable, and conforms with applicable PURPA and FERC guidelines.

Q. DID THE COMPANIES' OFFER A TEN-YEAR CONTRACT TERM LENGTH WITH TERMS AND CONDITIONS CONSISTENT WITH PURPA AND FERC IMPLEMENTATION GUIDELINES?

A. Yes. FERC requires that QFs have the option of either providing energy with avoided costs calculated at the time of delivery, or of providing energy and capacity with a LEO for delivery of energy or capacity for a fixed term length, with avoided cost rates specified either prior to the obligation incurred or based on avoided cost rates calculated at time of delivery. FERC gives state regulatory authorities broad latitude in setting avoided cost terms, including setting term lengths for fixed rate contracts. Act 62 requires utilities to include 10-year contract terms in the Standard Offer. The Companies' Standard Offers include variable, 5-year, and 10-year term options and the associated rates are included in the proposed Standard Offer Tariffs. The Standard Offer options are consistent with PURPA.

Q. ARE THE PROPOSED STANDARD OFFER CURTAILMENT TERMS AND CONDITIONS CONSISTENT WITH PURPA AND FERC IMPLEMENTATION GUIDELINES?

A. Yes. FERC regulations allow for curtailment of QFs for reliability or even economic reasons. In a potential curtailment circumstance, the utility must provide notice to the QF in time for the QF to cease delivering energy or capacity to the utility. FERC has affirmed that utilities purchasing under a LEO under PURPA include all relevant terms, including the circumstances justifying curtailment, in their PPAs. The Companies' proposed Standard Offers comply with PURPA.

In the proposed Standard Offer PPA's Section 5 and Exhibit A Energy Storage Protocol Item 4 specify that discharging storage energy is not permitted when the QF has received or is subject to a curtailment instruction from the Companies' system operators for reliability purposes. This means the QF must not discharge battery power when the system operators have issued a curtailment request for reliability purposes.

Section 17 of the Terms and Conditions of the PPA provides for curtailment of the QF during emergency conditions. I do not find any clauses related to economic curtailment, or of forcing the QF to sell less power than it could produce for non-reliability purposes.

Q. DO THE STANDARD OFFER AND PPA PROHIBIT TERMINATION OF THE PPA OR COLLECTION OF DAMAGES AS A RESULT OF INTERCONNECTION DELAYS AS CONTEMPLATED IN SECTION 58-41-20(E)(3)(A) OF ACT 62?

A. I do not find a specific provision allowing or prohibiting the termination of the PPA due to a delay in the development, construction, or commissioning of the interconnection facilities. There is potentially a provision for a delay without damages due if a delay is due to a Force Majeure event. Section 15 of the Terms and Conditions defines Force Majeure to include "actions or failures to act on the part of governmental authorities […] but only if such requirements, actions, or failures to act prevent or delay performance." In the event of a Force Majeure event, both parties are temporarily relieved of their responsibilities and obligations under the agreement, and these obligations resume with the resolution or end of the triggering event, the duration of which should not exceed twelve months. Section 15 does not provide for termination of the agreement in the case of a delay caused by a Force Majeure event.

I do not see a discussion of damages as a result of interconnection delays within the Standard Offer**.** Under Condition 2(a), the Seller is responsible for conveying or causing to convey to the utility all easements or rights of way for interconnections on or through private property and the Company shall not be liable to the Seller in the "event Company is delayed or prevented from purchasing power by Company failure to secure and retain" such rights of way. Regarding the interconnection process, this Commission has promulgated standards for interconnection of renewable energy facilities and other non-utility owned generation under Order No. 2016-191 (Docket No. 2015-362-E), which set forth the South Carolina Generator Interconnection Procedures ("SCGIP"). My understanding is that PURPA QFs with the intent to sell to the utility fall under one of the SCGIP processes, depending on the size of the QF. These processes and timeline of interconnection are specified under the SCGIP as specified in Order No.2016-191.

Q. DO THE STANDARD OFFER AND PPAS PROHIBIT THE COMPANIES FROM REDUCING THE PRICE PAID TO QFS BASED ON COSTS RESULTING FROM THE INTERMITTENT NATURE OF THE QF CONTEMPLATED IN SECTION 58-41-20(E)(3)(B) OF ACT 62?

A. No. The Companies propose an explicit cost for carrying increased operating reserves in the form of the integration services charges, which reduces the price paid to QFs based on the intermittent nature of the QF's production. I have provided commentary on this charge previously in my testimony.

Q. ACT 62 REQUIRES THAT THE COMMISSION APPROVE PPAS WITH "COMMERCIALLY REASONABLE" TERMS. CAN YOU DEFINE COMMMERCIALLY REASONABLE?

A. While I am not an attorney, I have some experience with contract terms. It is my understanding that the term "commercially reasonable" is used frequently in contracts, but neither FERC nor the South Carolina Legislature defined "commercially reasonable" in the context of Standard Offer contracts. Within the context of a party's contractual obligations, I would hold "commercially reasonable" to be synonymous with "reasonable best effort." As applied to contract terms as a whole (such as a PPA) which encompasses risk allocation and assignment of rights, responsibilities, and obligations, I would offer "commercially reasonable" to mean terms which would be acceptable to two independent parties engaging in a contract for their mutual benefit under their own free will.

Q. IN YOUR OPINION, ARE THE PROPOSED STANDARD OFFER PPAS AND TERMS AND CONDITIONS COMMERCIALLY REASONABLE?

A. In my opinion, the terms and conditions are generally commercially reasonable. As Witness Wheeler stated in his Direct Testimony (Page 12) some QFs have already committed under the existing provisions which indicates the terms and conditions are commercially reasonable. However, I have some concerns with the lack of clarity in some areas in the updated, redlined standard form that I address here. Although generally commercially reasonable, there is some inconsistency with PURPA that I will discuss later in my testimony.

The intent of the "Material Alteration" clause seems to be to limit the ability of the Seller to make material changes to the Qualifying Facility after the PPA is signed. This intention seems reasonable from the utility's perspective, in principle. As it is written, however, it is unclear how "estimated annual energy production" is defined, which is problematic because the PPA allows the Company to terminate the PPA if the QF produces energy in excess of the "estimated annual energy production." Section 1(i) discusses the Company's Right to Terminate or Suspend Agreement, and states that the Company "shall give Seller thirty (30) calendar days prior written notice before suspending or terminating the Agreement pursuant to provisions 1(i)(1) and 1(i)(3)(4)." This thirty-day notice does not seem to provide the Seller with a cure period during which the Seller may remedy the default or breach of the Agreement.

Furthermore, the definition of "Existing Capacity" when used in defining what constitutes a "Material Alteration" to the Seller facility is not precise. "Existing Capacity" is defined as the "estimated annual energy production" from the Facility in 3(f), but in Condition 5 the "Estimated Annual Energy Production" definition is not precise or clear: it states, "The estimated annual energy production from the Facility specified in the Purchase Power Agreement shall be the estimated total annual kilowatt-hours registered or computed by or from Company's metering facilities for each time period during a continuous 12-month interval." It is not clear from this language how this estimated annual energy production is determined, during what time periods, and at what intervals it is measured.

Q. ARE THERE ANY TERMS AND CONDITIONS IN THE STANDARD OFFER PPA WHICH ARE INCONSISTENT WITH PURPA?

A. Yes**.** The limitation that the PPA may be terminated in the event that the QF produces energy in excess of the "estimated annual energy production" is inconsistent with PURPA's "mandatory obligation".

Q. CAN YOU EXPLAIN WHY THIS IS INCONSISTENT WITH PURPA?

A. Yes**.** My understanding is that PURPA obligates a utility to purchase all the energy which a qualifying facility generates.[7] It is not inconceivable that, depending on how the "estimated annual energy production" is calculated, a QF might see a change in annual production greater than 5% due to weather variability. Thus, while the utility may reasonably set limits on changes to the QF in order to ensure that "material alterations" do not result in significantly increased changes in energy production, as I noted previously in testimony, the terms and conditions do not distinguish between these "material alterations" and other effects which might cause an increase in the avoided energy production of a QF.

Q. HOW DOES THIS INCONSISTENCY WITH PURPA IMPACT IMPLEMENTATION OF ACT 62?

A. Act 62 requires the Commission to strive to reduce the risks to ratepayers and ensure the Standard Offer is not discriminatory to QFs. The utility must purchase any

[7] In July 2019 the Ninth Circuit ruled in Winding Creek Solar LLC vs. Peterman et al. (Nos. 17-17531 & 32) that PURPA "…requires electric utilities to buy *all* the power produced by alternative energy generators known as Qualifying Cogeneration Facilities ("QFs")." (emphasis in original)
https://cdn.ca9.uscourts.gov/datastore/opinions/2019/07/29/17-17531.pdf

energy produced but is not required to purchase energy above the current avoided costs. The PPA can specify the energy and capacity that will be purchased at specific rates. The Commission may contemplate how the QF can be compensated for any additional energy produced and delivered to the utility above the contracted terms. The proposed Standard Offer contemplates refusal to accept the over-production, which violates PURPA standards. An alternative would be for the PPA to more clearly define the annual expected contract energy, with some expected variability due to changing weather conditions, and designate that any overproduction delivered to the utility will be compensated at the current approved variable rates as stated in the Standard Offer tariffs. The Act gives the Commission latitude on decisions relating to the terms and conditions, and I would recommend the Commission require the Companies to include terms and conditions in the Standard Offers relating to the compensation for any energy delivered to the Companies above the contracted amount. In my opinion, this would comply with PURPA, hold the ratepayers harmless, not discriminate against the QF, and be commercially reasonable.

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. ORS offers the following recommendations for the Commission consideration:

1) Approve the Companies' proposed avoided energy rates for Standard Offer contracts;
2) Approve DEC's proposed variable and 5-year avoided capacity rates for Standard Offer contracts;
3) Modify DEC's 10-year avoided capacity rate for Standard Offer contracts as recommended by ORS;

4) Modify DEP's variable, 5-year, and 10-year avoided capacity rates for the Standard Offer contracts as recommended by ORS;
5) As an interim step, approve the integration services charges as proposed by the Companies;
6) Require the Companies to update their integration services study in conjunction with any proposed changes to the Standard Offers. As part of the update, the Companies should be required to conduct technical workshops to gain input from the solar community and other stakeholders; and
7) Clarify the performance standards for a QF to ensure that the Companies remain obligated to purchase all of the energy a QF generates, while limiting the changes a QF can make to their systems.

Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Brian Horii

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner 1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Energy Resources, and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, and Ontario, Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, and South Carolina Office of Regulatory Staff.

Resource Planning:

- Authored the Locational Net Benefits Analysis (LNBA) tool used by California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island, demand response from large customers, and new clean power generation
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments
- Evaluated the sale value of hydroelectric assets in the Western U.S.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Author of the "E3 Calculator" tool used as the basis for all energy efficiency programs evaluations in California since 2006
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities
- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions; also authored the model's sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs

- Co-author of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005
- Principal consultant for the California Energy Commission's Title 24 building standards to reflect the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage
- Principal investigator for the 1992 EPRI report *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation

Cost of Service and Rate Design:

- Designed standard and innovative electric utility rate options for utilities in the U.S., Canada, and the Middle East
- Principal author of the *Full Value Tariff and Retail Rate Choices* report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings since 2008
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions
- Consulted to the New York State Public Service Commission on appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and appropriate cost tests
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997); principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix)
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs
- Testified for the South Carolina Office of Regulatory Staff on SCANA marginal costs
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work has addressed marginal cost-based revenue allocation and rate design; estimating area and time specific marginal costs; incorporating customer outage costs into planning; and designing a comprehensive billing and information management system for a major energy services provider operating in California

Transmission Planning and Pricing:

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in California's Central Valley
- Developed the quantitative modeling of net benefits to the California grid of SDG&E's Sunrise Powerlink project in support of the CAISO's testimonies in that proceeding
- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation

- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades
- Developed the cost basis for BC Hydro's wholesale transmission tariffs
- Provided support for numerous utility regulatory filings, including testimony writing and other litigation services

Energy and Climate Policy:

- Author of the E3 "GHG Calculator" tool used by the CPUC and California Energy Commission for evaluating electricity sector greenhouse gas emissions and trade-offs
- Primary architect of long-term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Project Manager, Supervisor of Electric Rates 1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept; projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models
- As PG&E's expert witness on revenue allocation and rate design before the California Public Utilities Commission (CPUC), was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC and extending their application to cost effectiveness analyses of DSM programs
- Created interactive negotiation analysis programs and forecasted electric rate trends for short-term planning

INDEPENDENT CONSULTING San Francisco, CA
Consultant 1989-1993

- Helped develop methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints; created a model for determining the least-cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs
- Co-authored *The Delta Report* for PG&E and EPRI, which examined the targeting of DSM measures to defer the expansion of local distribution facilities

Education

Stanford University Palo Alto, CA
M.S., Civil Engineering and Environmental Planning 1987

Stanford University Palo Alto, CA
B.S., Civil Engineering 1986

Citizenship

United States

Refereed Papers

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3. *Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*
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2. *Horii, B., (1995), "Final Results for the NMPC Area Costing and Distributed Resource Study," Proceedings Distributed Resources 1995: EPRI's First Annual Distributed Resources Conference, Electric Research Power Institute, August 29-31, 1995, Kansas City, Missouri*
3. *Orans, R., C.K. Woo, B. Horii and R. Pupp, (1994), "Estimation and Applications of Area- and Time-Specific Marginal Capacity Costs," Proceedings: 1994 Innovative Electricity Pricing, (February 9-11, Tampa, Florida) Electric Research Power Institute, Report TR-103629, 306-315.*
4. *Heffner, G., R. Orans, C.K. Woo, B. Horii and R. Pupp (1993), "Estimating Area Load and DSM Impact by Customer Class and End-Use," Western Load Research Association Conference, September 22-24, San Diego, California; and Electric Power Research Institute CEED Conference, October 27-29, St. Louis, Missouri.*